Incorporating Seismic Attribute Modeling into a Flow Model of the Grayburg Reservoir in the Foster-South Cowden Field, An Update.

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ABSTRACT

The Grayburg and San Andres reservoirs in the Foster – South Cowden Field have been producing since 1939, and under waterflood since 1962. Production had declined to near abandonment level at the start of this project. The objective of the project was to utilize low cost, state-of–the-art technologies available to small independent operators to preserve access to well bores and extend the economic life of mature fields. The use of an integrated team of a geologist, geophysicist, and engineer is not new to major oil producers. However, utilizing a team of experienced consultants along with in-house personnel is new at the smaller independent level.

The initial approach of this study was to construct a flow model with conventional data. Logs and cores provided the basis for the geological model. Production data was assembled and validated along with the few measured pressures taken early in the field's history. Production testing of all wells was initiated to provide accurate current production data. Pressure transient testing of all wells was initiated to provide accurate current bottom hole pressures. History matching of pressure and water-cut data validated the flow model, and the flow model has since guided field operations, subject to the limits imposed by the spacing of the well data (one reliable well log per 18 acres of reservoir). At this scale, compartmentalization and heterogeneity of the reservoir is obvious. The engineering history match and reservoir simulation, however, is conducted at one-acre (220 x 220 feet) spacing or less. 3-D seismic is required to define porosity in the areas between the wells and reduce the uncertainty inherent in data sets from old fields.

The 3-D seismic data set was processed to retain high frequencies, thereby improving vertical resolution to the range of 50 feet. Seismic bin size is 110 x 110 feet, equal to the scale utilized in the history match and reservoir simulation. Traces from the seismic inversion model exhibit a high degree of correlation with the well log data. A correlation was developed between seismic velocities and porosity for each geologic zone. The correlation was used to develop porosity maps for each zone in the flow model. The seismic derived/geologically guided maps delineated small-scale reservoir heterogeneities with a degree of confidence here-to-fore unavailable. The history match and reservoir simulation grids were reoriented to make use of a porosity barrier identified on the porosity maps. The resulting flow model was validated through the history match process, and used to guide the realignment of the waterflood.

The recommendations made during the project to date have resulted in the production of an additional 114,000 Barrels of Oil to date, an increase in the injection water quality, and a paradigm shift in the approach to data collection for day to day decision making. The initiation of the waterflood realignment program is aimed at extending the life of the field and the recovery of significant incremental oil. Five wells have been restimulated and the production from these wells has increased from 16 BOPD to 134 BOPD.

INTRODUCTION

Grayburg and San Andres restricted, shallow-water carbonate platform reservoirs on the Central Basin Platform have been prolific producers for over 75 years. Beginning in the 1950's, waterfloods were implemented in most of the major fields. Reservoir heterogeneities have resulted in low recovery efficiencies during both the primary and secondary phases of production in most fields. The conventional wisdom states that old fields, such as the Foster-South Cowden Field, are entering the final stage of their decline, that there exists little if any additional incremental reserves that can be produced economically, that well bores and equipment are beginning to fail, and once lost will not be replaced. That watercuts, already in the 90+ percent range will only increase, and that little could be done to reverse declining oil recoveries. It has been estimated that the eventual abandonment of these fields, in as few as 15 years, would occur as wells fall below their economic limits.

There is a need for a methodology, that can be made available to the small independent, which can reverse this decline. Methods pioneered by major oil companies, and presently being employed on large properties, have applications in smaller properties if they can be demonstrated to be both cost effective and within the technical capabilities of employees of, and consultants for, the smaller independents. Many small properties have been sold by large oil companies because it is uneconomic for large companies to apply the state-of-the-art technologies to the smaller properties. This study proves that state-of-the-art technologies, including 3D inversion modeling, produced and injection water chemistry analyses, modern field engineering testing methods, and the development of an integrated reservoir characterization can identify economically attainable incremental reserves in the leases of smaller producers.

OBJECTIVE

The objective of the project was to utilize low cost, state-of–the-art technologies, available to small independent operators, to preserve access to well bores and extend the economic life of fields by identifying incremental and bypassed reserves. The use of an integrated team of a geologist, geophysicist, and engineer is not new to major oil producers. However, utilizing a team of experienced consultants along with in-house personnel is new at the smaller independent level.

Paradigms describing the status of older fields need to be addressed and overcome. Some of the more established paradigms are: that the majors have done the right things to develop their reservoirs, that periodic long duration shut in build up tests and field wide water chemistry are not necessary, that a company of Laguna's size (9 full time employees) are too small to apply the technologies pioneered by the majors, that 3D seismic and inversion modeling do not have the "bang for the buck" in a smaller property(less than 640 acres), and that integrated reservoir characterization is too costly or has little return on investment.

The developed methodology had to be demonstrated to be cost effective, accessible to smaller independents, and capable of resulting in the development of incremental reserves at a low dollar-per-barrel cost.

Although this study is of a shallow shelf carbonate reservoir in the Permian Basin, the solution presented applies to fields in other basins and other reservoir classes as well.

APPROACH

With the aid of the DOE, Laguna Petroleum and Phillips Petroleum developed a two phase program for simulating the Grayburg/ San Andres reservoirs and determining the potential for incremental recovery of reserves through an integrated reservoir characterization, 3D seismic acquisition, interpretation, and inversion modeling, waterflood realignment, and an infill drilling and workover program. Although many of the Grayburg/San Andres reservoirs can be coaxed to give up accelerated reserves utilizing standard field management practices, it is believed that only by an integrated approach to field management, which includes a sequence stratigraphic based reservoir characterization, can significant incremental reserves be recovered.

The 3D survey was shot in August of 1994, but because of processing and interpretation problems, it was not available for integration into the simulation until Phase II in 1996. A geology based history match and engineering reservoir simulation was completed during Phase I. Cores existed for only one of the 5 wells cored in Section 36 although standard core analyses did exist for the remaining cored wells. A sequence stratigraphic model was built utilizing available core and log information. With 53 wells drilled in, or peripheral to, the section, it would be logical to assume that excellent control would be available. The reverse was true as the 40 acre 1940's vintage wells were not logged, and the deep (Canyon and Ellenburger) wells had, at best, cased hole neutron logs through the Grayburg/ San Andres. Only 34 wells have porosity logs usable in the construction of a porosity map for the identified flow units. The porosity maps generated for input into the history match and simulation had only one data point per 18 acres. The geology-only based history match was adequate to demonstrate sufficient additional potential to drill, recomplete and re-enter a number of wells,. and identify that the upper Grayburg contained significant bypassed and unswept reserves. A waterflood realignment was needed to recover these reserves. The history match also determined that the lower Grayburg had significant remaining potential and that the San Andres reservoir had been compartmentalized as a result of karstification and despite the largest OOIP was an uneconomic target. Phillips Petroleum sold their property in the project area at the end of Phase I. Laguna chose to continue into Phase II with their property (Section 36).

GEOLOGIC SETTING

The Foster-South Cowden Field is located on the eastern margin of the Central Basin Platform in central Ector County, Figure 1, immediately west of Odessa, Texas. Like most San Andres and Grayburg reservoirs, Foster-South Cowden is situated on the shallow shelf at Grayburg time, which trend north to south and oblique to the paleo-wind direction. Major deep seated uplifts to the west form the spine of the Platform and restrict the shelf to a width of six to 10 miles from shelf edge to sabkha. The field is part of the trend of San Andres – Grayburg production that extends from Yates Field at the southeast, to Seminole Field at the north end of the platform

FIELD HISTORY

The Foster-South Cowden Field has a history typical of many fields in the United States. Oil was first discovered in the Foster-South Cowden Field in 1934. Production was established in the study area in 1939. The property, originally owned by ARCO and Sun, Figure 1B, was developed beginning in 1940, complete open hole, shot with nitroglycerine, and developed on 40 acre spacing. The field produced from 550 feet of gross pay and as much as 200' of net pay in the upper and lower Grayburg and San Andres. The wells were hydro-fracture stimulated in 1955 which resulted in a three fold increase in production. In 1962, the poorest producer on each 160 acre tract was converted to injection, initially injecting on vacuum as the field pressure had been severely reduced since 1939. In the 1970's an infill drilling program reduced spacing to 20 acres. No structured waterflood with an identifiable pattern has ever been attempted. The "waterflood" as it exists today, is a partial line drive.

Production from the Canyon and Ellenburger was also established during the 1970's bringing the total well count in the section to 53 (including 4 lease line injectors). Injection profiles indicate that over 80% of the water was being injected into the upper Grayburg, 5% into the lower Grayburg, less that 5% of into the San Andres, and the remaining injection going "out of zone".

Laguna purchased the NE/4 of Section 36 in 1990 and the remaining ¾ of the sectionin 1992, anticipating that with prudent, well established field management, the property would have as economic life of +/- 15 years.

METHODOLOGY

Geophysics

The 3D seismic survey acquired is 3.3 square miles, intended to image the Grayburg reservoir at 4,000 feet. One requirement for the DOE is to develop a methodology for other workers to use multiple scientific disciplines, and this report details the geophysical work done in a "cookbook form". Another DOE objective is to give independent operators the ability to apply these methods using inexpensive computers and software. The Inversion Modeling process was accomplished within these criteria at the offices of Laguna Petroleum.

Maps have been made using analyses of seismic Inversion Model data (calibrated to well data) to show the distribution of gross average rock porosity of several oil productive zones of the upper Grayburg formation beneath the 3D shoot. These data were factored into an engineering model to define reservoir capacity and preferred fluid flow, explaining the historical production of oil and water and the injection of fluids. This overall model has guided decisions for future expenditures for workovers, recompletions, and new wells. Figure 1a &1b compares a map of the seismic-derived porosity distribution with a map made using only log-derived porosity data, and demonstrates that increased data density offers a more complete image of porosity distribution.

The overall task defined for the geologist and geophysicist is to define geologic parameters significant to the production and determine ways to map those parameters. When the engineer is initially involved with those decisions, his needs and concerns can be addressed as part of that task. Primary among his needs are production zone-dependent reservoir characteristics at the scale of the reservoir, specifically, the flow unit scale. Quantitative, not relative values are required to be useful for production history comparison. Reservoir porosity is the factor with the most influence on production and waterflood injection; permeability is proportionally related to productive porosity in this project area.

A seismic interpretation of the Grayburg is simplified since that sequence contains no seismically discreet siliciclastic layers within the reservoir in this project area that would affect the seismic data. Changes in porosity will cause a seismic reflection response because porosity affects sonic velocity, thus, acoustic impedance. Thickness of producing zones is measured using log correlations of thin siliciclastic markers. The thickness maps are essential to calculate the same zones for the seismic data analysis. Porosity values are determined from log calculations. Structure is not a primary factor controlling production at the project scale, but may have profoundly affected facies distributions. The geophysical task is to isolate production zones in seismic time, convert the seismic data to a reservoir-quantitative form, and to produce maps of value to the engineer for detailing the distribution of oil in place.

The first consideration for the seismic analysis of any project is where to begin, since different projects have different geologic considerations. Tracking seismic reflectors and making time and reflection amplitude maps are a start, but do not define the critical factors of rock properties. Seismic waveform attributes are a button-click away, but analyses of results are vague and probably useless on the required scale, even when applied critically. The foundation of the project is to relate seismic data to well data through theory, as preferable to empirical or statistical methods. Results are then understandable and errors are noticeable. Inversion model results can be evaluated in context with rock properties, whereas waveforms (wiggles) are essentially in a foreign script, a convenience of data recording. Reflections are only a response to relative rock property changes. Why would a geophysicist be negative about reflections? Because reflections don’t contain the quantitative answers, as will be shown.

Inversion Modeling

Seismic reflection data have no stratigraphic significance ... until geologic data are incorporated using well control and interpreter experience. Actually, a number of technical points (phase, for one) must be met to even qualify any seismic display.

Inversion Modeling is a process that removes the ambiguities of the seismic wavelet to establish some uniqueness to the data model. The model then has some characteristics of the stratigraphy to which the seismic data are the response. In a nutshell (which will be cracked later) **Inversion Modeling removes the wiggle and infuses geologic constraints into the seismic data set**. A discussion of Inversion Modeling procedure follows in the methodology. Figure 2 shows profile L-L', an example of the seismic data in the project. The zone of most interest is only about 24 milliseconds of the upper Grayburg. Figure 3 is an enlargement of a part of the data in figure 2, showing the Inversion Model traces.

Expectations from the seismic data will be considered from acquisition and processing parameters. The survey data quality embodies actual fold, noise, wavelet bandwidth and phase. The scale of the geology to be imaged is compared to the resolution of the seismic analysis. Inversion Modeling reveals the sensitivity of seismic traces to the qualities of wavelet and noise, and model traces may represent the true seismic resolution.

A number of expected intrinsic problems of defining rock properties are considered. Porosity values are measured from logs, but calibration varies with log type. The difficulty of normalizing porosity values causes inherent scatter in the porosity calibration data set. Reservoir anhydrite also complicates porosity measurements. Sonic velocity (both seismic and log-derived) responds to changes in primary porosity but is not very responsive to vuggy porosity. By comparison, the neutron-sourced log device measures total porosity. Lithology contrasts can potentially appear seismically the same as rock property changes. Synthetic seismogram models show that geologic correlations are not represented by reflections, so that placement of analysis zone boundaries in x, y, t space contains some error. Waveform attributes will not define rock properties in thick carbonate reservoir situations; reflections do not quantify reservoir properties but only show relative changes.

Inversion Model building is an important tool of geophysics for quantifying rock properties. A brief description of the method is intended to reveal the requirements for model building and the "do-it-yourself" nature of modeling using the PC. The interpreter familiar with the geology will be best qualified to assess the model results. The software used for this project is Vest Exploration Services 3DINV program. It creates a model controlled by user constraints. The modeling is performed using a Generalized Linear Inversion (GLI) method that, by iteration, converges on a best result. This program internally creates a pseudo-sonic log trace from each seismic trace. Constraining the model refers to infusing into the model traces values of sonic velocity and horizon location; other constraints of known waveform characteristics of amplitude and frequency bandwidth are absent from the model traces. Phase of the input seismic data must be zero. The results of a model are greatly influenced by data quality. Seismic noise is the worst contaminator since it decreases the accuracy of seismic reflection placement and amplitude. Data processing methods involving wavelet shaping, specifically of frequency and phase, affect model trace accuracy and vertical resolution.

Model Analysis is the ultimate goal and produces the maps needed. Techniques used for the Grayburg are described in the step-by-step discussion that follows. The qualification of the model accuracy and resolution rely on the model analysis of geologic zones and relationships to subsurface knowledge.

The upper Grayburg zones appear to be well described in the final analysis. However, seismic relationships for lower Grayburg zones (source of some oil production) with subsurface data have not been strong enough to be of value. Similarly, work with the San Andres has been unfulfilling. The reservoir internal structure of these problem zones is more complicated and analysis zones are thinner. Lateral relationships in the karsted San Andres are complex compared to the upper Grayburg.

Production History

1. Past production was estimated and allocated to correlated zones of the upper Grayburg.

Geological Preparation

(for a more complete review of the geological portion of the study, the reader is referred to the 1996-1997 and 1997-1998 annual reports and the tech transfer presentations listed at the end of this paper.)

1. Geologic data were prepared in a data base format. Available logs were correlated, production zones were defined, and log correlation's were made for important zone boundaries (Figure 4).
2. Depth (Figure 5) and thickness (Figure 6) maps were made of the major production zones (typically 100'-200' thick). Zones were subdivided into zones as thin as about 50' for further study.
3. Digitized neutron, density, and sonic log curves were used to calculate porosity and its relation to zone thickness. Average porosity, and other porosity parameters were calculated for the upper Grayburg zones. Gross average porosity is the parameter most likely sensed by the seismic tool.
4. Relationships of log properties were studied in core and logs. A very important revelation observed from core study is that lithology throughout the Grayburg is consistently dolomite and anhydrite, so that non-carbonate lithologies are unlikely to complicate the seismic analysis.

Geophysical Procedure

1. Basic, conventional seismic time maps were made for the Queen, lower Queen, Grayburg, San Andres, and Holt reflections. Waveform attributes associated with some of these reflections were observed.
2. Synthetic seismogram models (Figure 7 & 8) were made to examine seismic relationships to geologic data. The top of the Grayburg A zone geologic correlation is represented as a reflection in the west part of the 3D survey but not in the east part because of dolomite within the lower Queen. The other Grayburg zones do not have associated reflections at all since they are not bounded by significant non-carbonate clastic beds.
3. Sonic logs integrated in time were measured for interval time and thickness to determine average velocity of each zone. Figure 4 shows the sonic log with the velocity calculations, the synthetic seismogram and the Inversion Model traces at the well tie. The figure provides a comparison of the three data types, and a sense of the resolution of each. This velocity field from all sonic logged wells was mapped (contoured) and digitized for the area of the 3D survey. These contour

maps were revised for final use by considering the distribution of velocity from inversion-derived maps. The final isochron maps were calculated using these velocity maps.

3. Isochron maps were calculated from subsurface-mapped isopach and the interval velocity maps. In fact, a depth to time conversion was done. Time thicknesses were mapped for the Grayburg A, B, and C zones.
4. An inversion model was calculated for the 3D volume. The input parameters for the model include reflection horizons, sonic velocities determined from logs, and frequency and amplitude characteristics of the seismic data. In common with the 3D survey, the model traces replace seismic wiggle traces. The model trace lengths (in time) are shorter than the seismic traces, since they are windowed from 500-1100 milliseconds around the zones of study.
6. Profile comparisons were made of the model traces with the sonic logs in time for qualification purposes. The inversion model traces have a minimum resolution of about 50 feet, compared to the sonic log with one foot resolution, or a wiggle trace of undefined resolution. Refer to Figure 3.
7. The lower Queen reflection horizon picks were edited on the Inversion Model traces to map the lithologic boundary of the top of the lower Queen clastics. This horizon is the **reference** for horizon building the Grayburg horizons. The lower Queen is a reasonable lithologic boundary near the top of the Grayburg.
8. Isochron maps were successively added, beginning with the lower Queen reference, to build horizons for the A, B, and C. Deeper horizon levels were also calculated for the Grayburg, as well as the San Andres. For example, the isochron of the lower Queen to Grayburg A interval, added to the lower Queen time horizon, yields a time horizon for the Grayburg A.
9. Average Interval Velocity was calculated from the Inversion Model for the Grayburg A and B zones, using the zone boundary horizons and the interval averaging routine in the Vest seismic software. These maps represent the seismic response to dolomite velocity at specific places in the rock sequence.
10. The values of Average Interval Velocity were graphically compared to well log-derived values of Gross Average Porosity at well locations. The zones analyzed in the Inversion Model lie between the calculated time horizons. Figure 9 shows the cross-plot relationship of gross average porosity with seismic-derived velocity for the Grayburg A zone (thick line). A Schlumberger chart (curved dashed lines) shows the commonly used relationship of sonic log velocity and measured porosity. That chart has been used as a guide to judge the normalized values of velocity from the Inversion Model and to interpret the slope of the line used to convert the velocity data to porosity data.
11. A linear function was determined from the cross-plotted points, and was used to convert the Inversion Model velocity values to Gross Average Porosity values using the Vest software. The map of calibrated Gross Average Porosity of each Grayburg zone was used in the production history model.
12. Quality of the seismic-derived porosity map was partly assessed by the scatter within the alignment of cross-plot points. By comparison, that scatter is comparable to the scatter of laboratory-derived relationships of velocity and porosity.

Seismic Derived Porosity Maps

Seismic-derived porosity maps for the Grayburg A and B zones are shown in figures 10 and 11. These zones comprise the upper part of the Grayburg and are reservoirs for the significant historic production. The complex areas of high porosity within the A zone are adjacent to areas of much lower porosity. Water injection wells placed in the low porosity areas might not be effective for moving fluids toward producing wells. A significant trend in the A zone is the southwest oriented low porosity area that coincides with the structural break in the southeast part of Section 36 (see Figure 5). As a barrier to fluid flow, the engineering simulation was reoriented to parallel the anomaly. The B zone is, on average, less porous than the A zone, but was included in the fluid simulation. A brief supplemental study of the gas-to-oil ratios measured for the Grayburg production was made from early records. GOR values in Section 36, west of the A zone porosity barrier are about one-fourth of the values on the down-dip side of the barrier in Section 31. A discontinuity of the A zone reservoir is strongly suggested by that relationship. The barrier may be a stratigraphic trap to fluid movement, demonstrated by high GOR values at the updip limit. Waterflood attempts across such a barrier would be pointless.

The seismic-derived porosity data were exported as spreadsheet values of x, y, and porosity to engineering software that contains data from historic production of oil, gas, and water, zone thicknesses, and other relevant parameters. The more densely defined porosity distribution contributed to building an optimum reservoir model. The objectives of that model are to determine remaining oil in place and optimum ways of extracting it. The reservoir model is qualified by the match with production history. This model is the basis of understanding waterflood effectiveness and of planning recompletions, new wells, and abandonments.

The surface seismic tool holds great potential for characterizing carbonate reservoirs in the Permian Basin. Although specific local problems must be addressed in the approach to analyzing the data, Inversion Modeling is an important step in converting seismic data into an intuitively useful form. Ultimately, the multi-disciplinary approach is necessary to produce hundreds of millions of barrels of oil already discovered.

ENGINEERING

Simulation Results

Flow models were built specifically to test the seismic-derived porosity maps (see Geophysics). After reviewing the seismic derived porosity map, it became apparent that the simulation grid needed to be rotated approximately 45 degrees to match a no-flow boundary (a very low porosity trend parallel to a break in slope in the Foster-Pegues lease). The original simulation grid was oriented parallel to the section lines as the "geology only" porosity map was not of sufficient detail to define the no flow boundary. The flow models considered only Section 36. Separate models were built for each upper Grayburg layer (A, B, and C). The purpose was to directly compare the oil in place (OOIP) for a model built from the seismic-derived porosity map to the OOIP for a model built from well values and then history matched. Initial comparison indicated that the

OOIP from the seismic-derived porosity maps was about 50% greater than the OIP from the history matched model. The velocity to porosity transform to create the seismic maps was adjusted until the values of OOIP were within 20%. At that point the conventional history matching process started.

Although similar to the original simulation, the reoriented simulation exhibited significant differences in the distribution of present day water saturations. A suite of bottom hole pressure tests was begun on all wells that have not already been refractured. The new simulation will be run again in the future when the pressure buildup tests, produced water analyses, additional production and data from additional refracs are completed and analyzed.

The upper Grayburg is now the primary target in the study area. Completions in the San Andres have demonstrated the limited nature of the reservoir. As previously discussed (see 1996 – 1997 Annual Report), the karst event at the end of the San Andres has compartmentalized the reservoir in this portion of the platform. The lower Grayburg has also been isolated and tested in a number of wells and appears to be a candidate for waterflood at a later date. CIBP's are being set above the San Andres and lower Grayburg zones so that, in the future, the zones can be re-entered. In most of the wells, the lower Grayburg and San Andres were completed through a single set of perforations and a single frac. Therefore, we will refer to the lower Grayburg and San Andres as a single unit, the lower Grayburg/San Andres. The upper Grayburg waterflood (A, B, and C zones) has become the focus of the project. The high confidence level in the upper Grayburg seismic derived porosity maps re-enforces the decision to enhance the existing waterflood.

Field Engineering Objectives

Together with the continuous testing and monitoring of bottom hole pressures, individual well production, injection volumes, injection pressures, injection profiles and day to day operations, the engineering objectives of the year were to:

- Redirect the focus of the project on the re-alignment of the upper Grayburg waterflood
- Isolate the upper Grayburg in wells producing from multiple intervals
- Initiate a new bottom hole pressure testing procedure and program
- Implement recommendations derived from bottom hole pressure data.

Re-Alignment of Upper Grayburg Waterflood

The re-alignment of the upper Grayburg waterflood became the focus of the study area throughout 1998. Completion attempts in the San Andres had little success due to the limited nature of the reservoir. Tests in the lower Grayburg have indicated the interval to be productive. However, efforts to produce and waterflood both the upper and lower Grayburg in tandem have proven to be unsuccessful and inefficient due to the difference in reservoir characteristics.

Thus, it was decided to plug back and isolate the upper Grayburg in all wells producing from multiple intervals and focus the project on re-alignment of the waterflood for the upper Grayburg. Figure 12 identifies the wells currently producing from the upper Grayburg that have been restimulated. These wells highlight the inefficiency of the so called "flood pattern". Although wells were originally drilled in a pattern adequate to flood the upper Grayburg, the present distribution of upper Grayburg emphasizes the need for the flood to be re-oriented, and available P & A'd and T & A'd to be utilized. Prior to running the final re-oriented simulation (see simulation) it was necessary to gather as much additional information on the upper Grayburg as possible. Production tests, water analysis and a new suite of bottom hole pressure test were taken on all wells before and after isolating the upper Grayburg.

Bottom Hole Pressure Testing

Initial bottom hole pressure information obtained during the project was considered insufficient to aid in the re-alignment of the upper Grayburg waterflood. Previous bottom hole pressure tests were very short in nature. Generally, the tests lasted for a duration of three to four days and required a significant amount of extrapolation of the data. Due to the short shut-in periods, the results were uncertain and were considered unusable. Thus, a revised testing procedure and program was initiated for the project.

The new testing procedure consisted of continuously analyzing the data during the shut-in period. The tests were continued until a reasonable data set was collected for interpretation. On average, a good data set was collected after approximately 900 hours of shut-in time. Additionally, great attention and detail was given in the actual data gathering in the field.

Recommendations

As a result of the plug backs, production tests, and new suite of bottom hole pressure tests, it became apparent that although many of the wells have been a part of a waterflood for 30 years, their capability of producing fluids was poor. This is a result of the very short frac wing lengths achieved during a fracture program performed on the leases in the late 1970's and early 1980's. The fracture treatments pumped at that time consisted of 40,000 gallons of fluid and 20,000 lbs of sand. Although the treatments achieved initial producing rates considered as successful, the relatively small treatments created short frac wing lengths resulting in rapid production declines.

Based upon high bottom hole pressures, short frac wing lengths and low total fluid production, it was recommended to initiate a re-stimulation program for the upper Grayburg. Seven wells were identified and recommended as re-frac candidates. Three wells, the Brock #6, Brock #5 and Foster-Pegues #8 were re-stimulated in 1998. It was determined much larger treatments needed to be utilized to achieve greater frac lengths. The treatments, designed to obtain frac lengths of up to 180', averaged 28,000 gallons of fluid and 104,000 lbs. of sand. Producing rates in the wells prior to the treatment averaged less than twenty barrels per day. After initial declines following the treatments, the rates stabilized at over 150 barrels of fluid per day resulting in a seven fold increase in sustained production (see figure 13).

A standard water analysis costs $75.00. A bottom hole pressure test is included as part of daily operations and is a no-cost item. The cost to analyze a bottom hole pressure is $425.00. The production "lost" during a 30 day build up test is quickly recouped as flush production after the well is returned to production. A fracture stimulation, without new well equipment is $25,000.00. All costs are approximate and fluctuate with the price of oil.

ACCOMPLISHMENTS

The major accomplishment of the project has been demonstrating that state-of-the-art technology can be economically applied to smaller properties (+/-640 acres) operated by independent operators. The project has proven that reservoir characterization, including periodic water chemistry analyses and production tests, long duration shut in build up tests (data collection), integrated core and log data, and 3D seismic and inversion modeling can be performed on smaller leases in a timely and cost effective manner.

The recommendations made during the project have resulted in the production of 114,000 Barrels of incremental oil to date. Coincident with the 7 fold increase in oil production in the five refraced wells (from 16 BOPD to 134 BOPD) was a 13 fold increase in water production. The water production from the 5 wells rose from 74 BWPD to 959 BWPD. This water was needed for injection as the results of the simulation indicated that an increase in injection in the reservoir was a necessary part of the waterflood realignment program. In addition, the injection water quality has been improved through changes in the water system.

For the first time, the reservoir has also been divided into its component parts. The upper Grayburg is a 68 year old field with a 37 year old waterflood in need of realignment. The main waterflood target remains the upper Grayburg where significant bypassed and incremental reserves remain to be exploited. The lower Grayburg is at near virgin reservoir conditions in part of the field and is a future candidate for waterflood. In order for the waterflood to be viable, access to as many well bores as possible need to be maintained. The San Andres is a compartmentalized reservoir with a large OOIP but very low recoveries. Completions in the San Andres have resulted in good initial potentials but very low ultimate recoveries. Presently, technologies are not available to make San Andres completions economic.

APPLICATIONS

The results of this project demonstrate that low cost state-of-the-art technology and integrated reservoir characterization can be utilized to preserve access to existing well bores, prolong field and reservoir lives, and enhance ultimate recoveries. This methodology is applicable to not only shallow shelf carbonate reservoirs in the Permian Basin, but is also applicable to carbonate fields in other basins and fields in and other reservoir classes.

The use of long duration shut in buildup tests, water chemistry analyses, and 3D seismic inversion modeling has been demonstrated to be both cost effective and available to the small independent. The use of inexpensive, off the shelf geological, geophysical and engineering software packages which all run on a PC platform, and the integration of familiar engineering, geological, and geophysical practices in the integrated reservoir characterization provides a “comfort factor” for independents.

FUTURE ACTIVITIES

Laguna has developed a management plan for each well in the project area and identified action items for each well. Laguna has initiated extended shut in build up tests and periodic production tests and produced water analyses on their offset leases to the east and west. They have also completed a series of tests in a deep water clastic unit in the Delaware Basin, and will soon initiate testing programs on other leases. Offset operators and a number of operators with leases on trend have requested more information, reviews of the project, or have expressed interest in having a review of their properties to determine if the methodology developed here was applicable to their leases.

In the next six months, Laguna plans to drill one producer, one lease line injector, acidize two wells, re-enter two wells to convert to injectors, re-enter one well to place back on production, and re-frac two wells as part of the upper Grayburg waterflood realignment. In addition, one well will be deepened to the lower Grayburg. The results of this activity will be monitored and based on results additional well work planned. This program is aimed at extending the field life beyond 10 to 15 years and recovering significant incremental oil. The upside potential for the project area is estimated to be 3,000,000 barrels of incremental oil bringing the recovery factor from 12.5% to almost 19%.

We are committed to presenting as many tech transfer events as possible, targeting operator, engineering, geologic, and geophysical audiences. We will continue to update out website (www.lagunapetrol.com) as often as necessary.

RECENT TECH TRANSFER EVENTS

(In Reverse Chronological Order)

Trentham, R. C., and K. Widner, 1999, Using Produced Water Analyses to Evaluate Production Problems and Recompletions in an "Old Waterflood", an Update: Foster-South Cowden Fields, Ector County, Texas, in Luftholm, P. and G. Hinterlong, eds., Permian Basin: Providing Energy for America: West Texas Geological Society Symposium, in Press.

Trentham, R. C., and K. Widner, 1999, Using Produced Water Analyses to Evaluate Production Problems and Recompletions in an "Old Waterflood": Foster-South Cowden Fields, Ector County, Texas, in J. Campell, ed., Mapping the Future: Fundamental Geology/New Technology, Transactions and abstracts of the AAPG SW Section Convention, Abilene Geology Society, Publication 99-1, p. 85, and extended abstract.

Robinson, William C., 1998, The Role of Seismic Inversion Modeling in Describing Reservoir Characteristics: A Case Study, in Bulletin of the West Texas Geological Society, Part I in Dec. 1998, vol.38, no.4., p.4-11 and Part II in Jan.1999, vol.38, no.5 p. 4-8.

Robinson, William C., 1998, The Role of Seismic Inversion Modeling in Describing Reservoir Characteristics: A Case Study presented at Society of Professional Earth

Scientists III Seismic Symposium, November 11, 1998, in Midland, Texas. The abstract appears in the Symposium publication.

Weinbrandt, Richard M., R.C. Trentham, W.C. Robinson, 1998, Incorporating Seismic Attribute Porosity Into a Flow Model of the Grayburg Reservoir in the Foster – South Cowden Field SPE#39666. In ed. W.D. DeMis and M.K. Nelis, "The Search Continues into the 21st Century": West Texas Geology Society Pub. 98-105, p.231-238. Presented orally at the Symposium, October 31, 1998.

Weinbrandt, R. M., R. C. Trentham, W. C. Robinson, 1998, Incorporating Seismic Attribute Porosity Into a Flow Model of the Grayburg Reservoir in the Foster – South Cowden Field SPE#39666. SPE/DOE Eleventh Symposium on Improved Oil Recovery, Tulsa, Oklahoma, April 19-22, 1998. Proceedings, vol. 2, p. 115-128.

Trentham, R. C., W. C. Robinson, R. M. Weinbrandt, 1998, The Use of Core in an Integrated 3D Seismic, Geological, and Engineering Study of the Grayburg/San Andres of Foster and South Cowden Fields, Ector County, Texas, in. E. L. Stoudt, D. W. Dull, and M. R. Raines, eds., Permian Basin Core Workshop – DOE Funded Reservoir Characterization Projects: Permian Basin Section SEPM Core Workshop, Publication 98-40, 22 pages.

Robinson, W. C., R. C. Trentham, 1997, Practical Mapping of Lithology and Rock Properties Using Analyses of Seismic Inversion Models, in W. D. DeMis, ed., Permian Basin Oil and Gas Fields: Turning Ideas into Production: West Texas Geological Society Symposium, Publication 97-102, p.105.

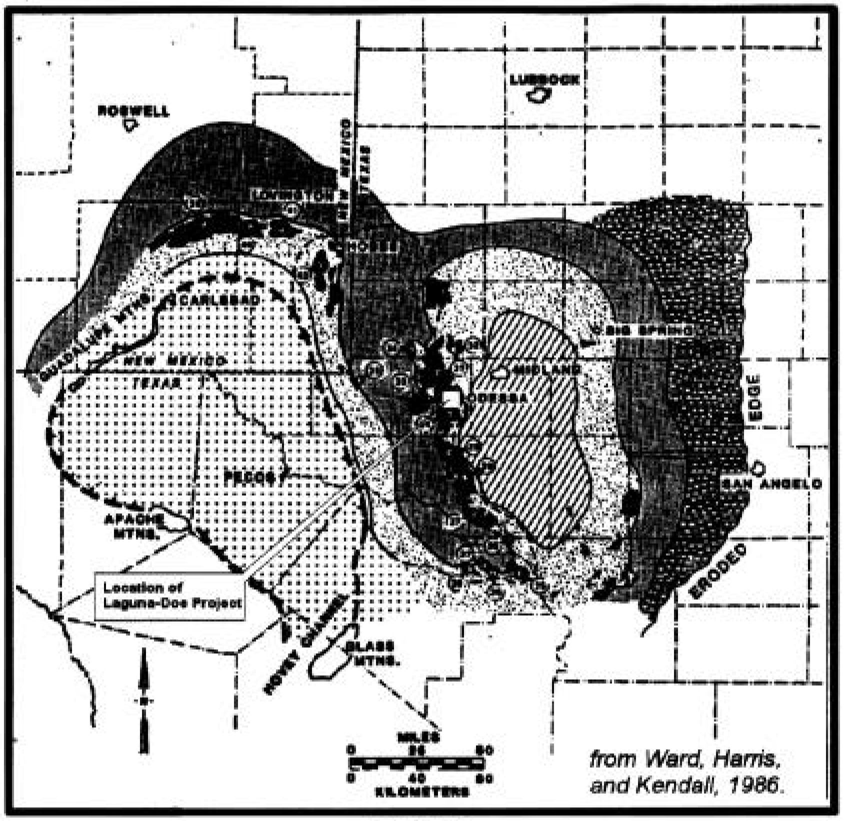
Trentham, R. C., W. C. Robinson, R. M. Weinbrandt, 1997, How an Independent Operator Can Integrate Engineering, Geophysics and Geology in a Reservoir Study: Grayburg/San Andres of Foster and South Cowden Fields, Ector County, Texas, in. W. D. DeMis, ed., Permian Basin Oil and Gas Fields: Turning Ideas into Production: West Texas Geological Society Symposium, Publication 97-102, p. 109.

A presentation titled, "How An Independent Can Integrate Geology, Geophysics, And Engineering To Enhance Reserves In An Old Field", was made by R. C. Trentham to the Kansas Geological Society on November 5, 1997 in Wichita, Kansas.

ACKNOWLEDGEMENTS

The work on this project was performed under contract # DE-FC22-94BC14982.
Robert C. Trentham is the Laguna Petroleum contact for this project. Dan Ferguson at the National Petroleum Technology Office (1-918-699-2047) is the Contracting officer's Representative (COR). The project began Aug 2, 1994 and will be complete Aug, 2,1999. We would like to acknowledge James J. Reeves and Hoxie W. Smith for conceiving and managing the DOE study and for being responsible for the geophysical study. Since April 1996, William C. Robinson has been responsible for reprocessing and reinterpreting the

seismic data and for the geophysical study. Also since that date, Robert C. Trentham has been responsible for project management.

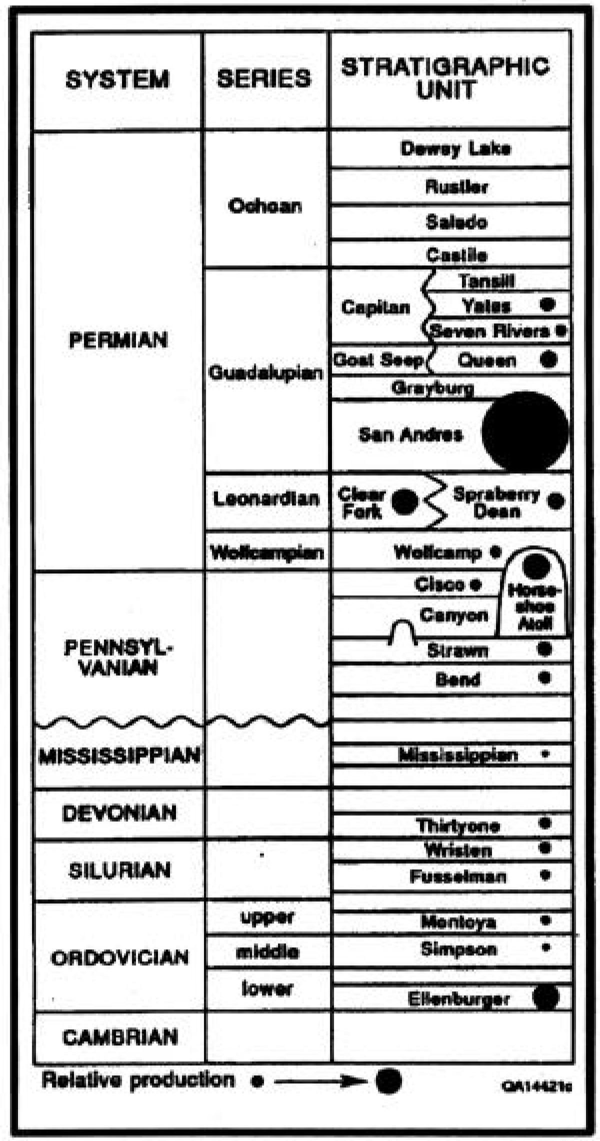


from Ward, Harris, and Kendall, 1986.

PERMIAN
MIDDLE GUADALUPE SERIES
GRAYBURG FORMATION

- CAPITAN "REEF" FRONT (SUBSURFACE)
- DELAWARE BASIN–CHERRY CANYON FORMATION BASINAL SANDSTONE, SILT, SHALE AND LIMESTONE
- DOLOMITE
- ---- OUTLINE CENTRAL BASIN PLATFORM
- OILFIELDS LISTED IN TABLES
- EVAPORITIC FACIES–DOLOMITE, POROSITY PLUGGED BY EVAPORITES.
- LIMESTONE
- ANHYDRITE AND HALITE RED SANDSTONE, RED SILTS, RED SHALES AND BEDDED ANHYDRITE
- OIL OR GAS FIELD

SIMPLIFIED GEOLOGIC MAP OF THE GRAYBURG FORMATION, PERMIAN BASIN, SHOWING THE LOCATIONS OF PRODUCING FIELDS. SEE TABLE 2 IN APPENDIX FOR DETAILED DESCRIPTIONS OF THE NUMBERED FIELDS.



Paleozoic section in West Texas showing relative importance of oil producing unit (from Galloway and others, 1983).

Figure 1. Location Map for the Laguna-DOE Project and Stratigraphic Column.

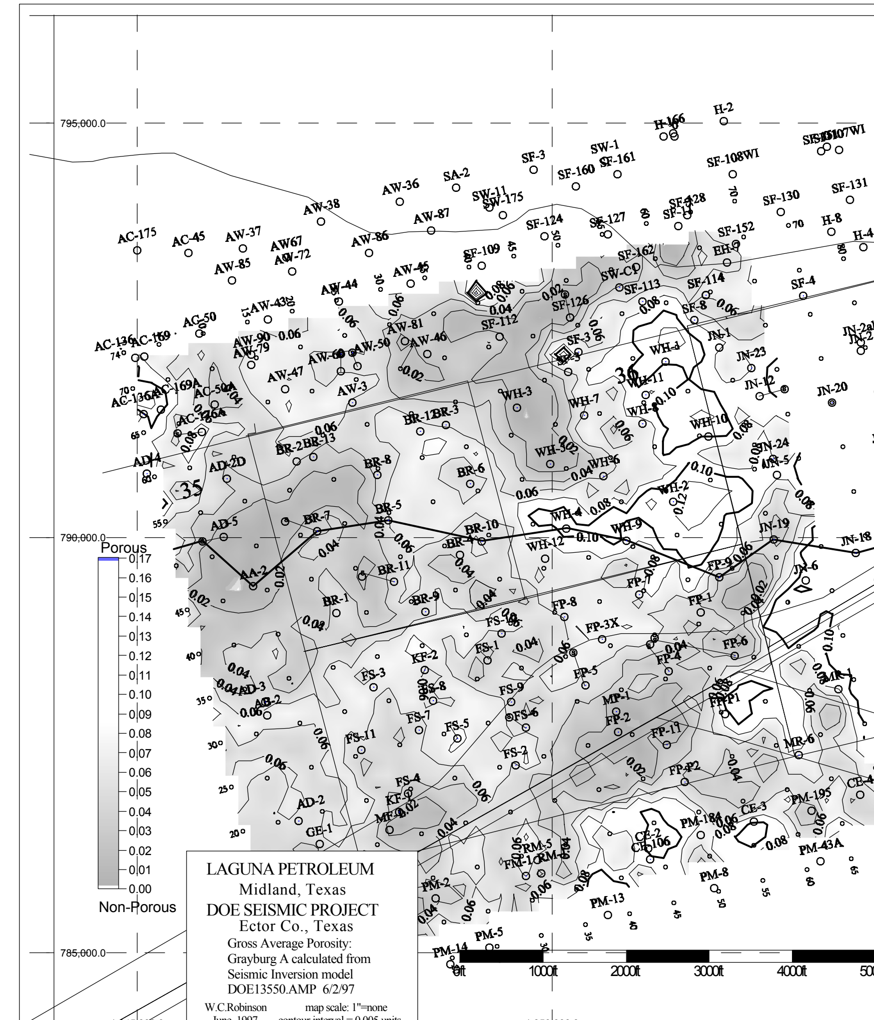


Figure 1A. Seismic Inversion-Derived Gross Average Porosity Grayburg A zone.

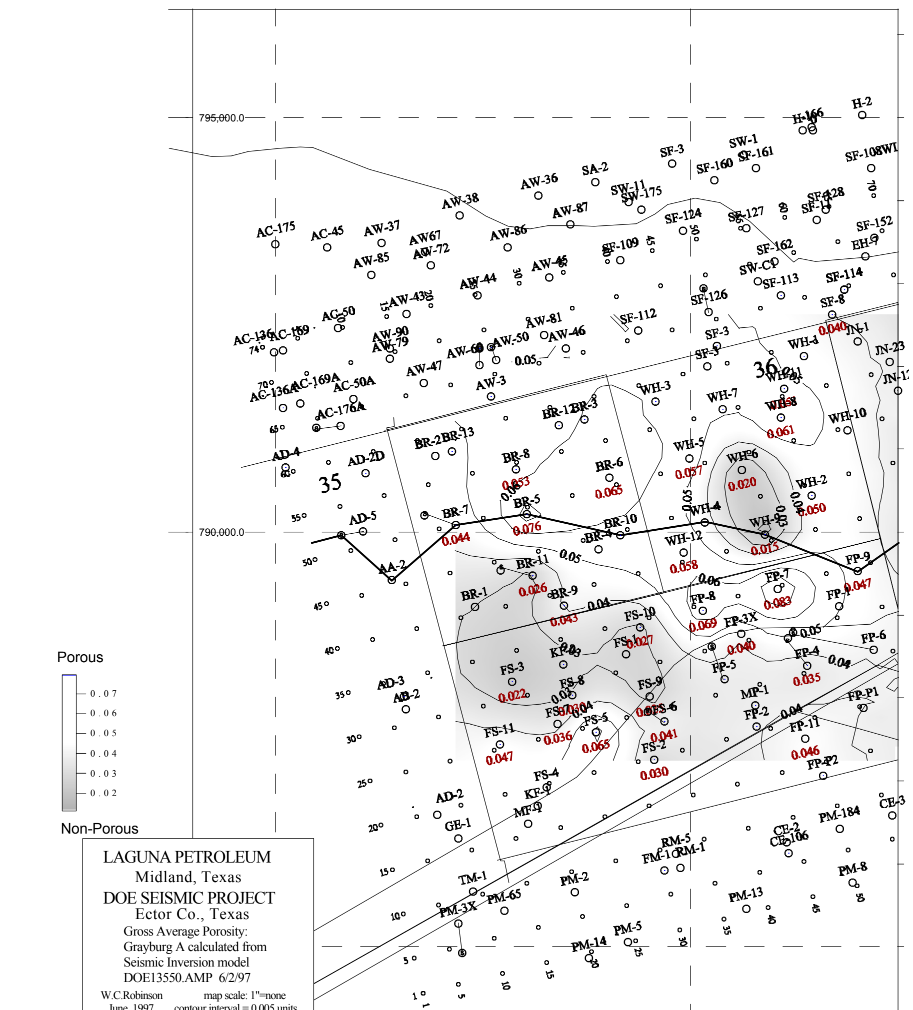


Figure 1B. Well log-Derived Gross Average Porosity Grayburg A zone.

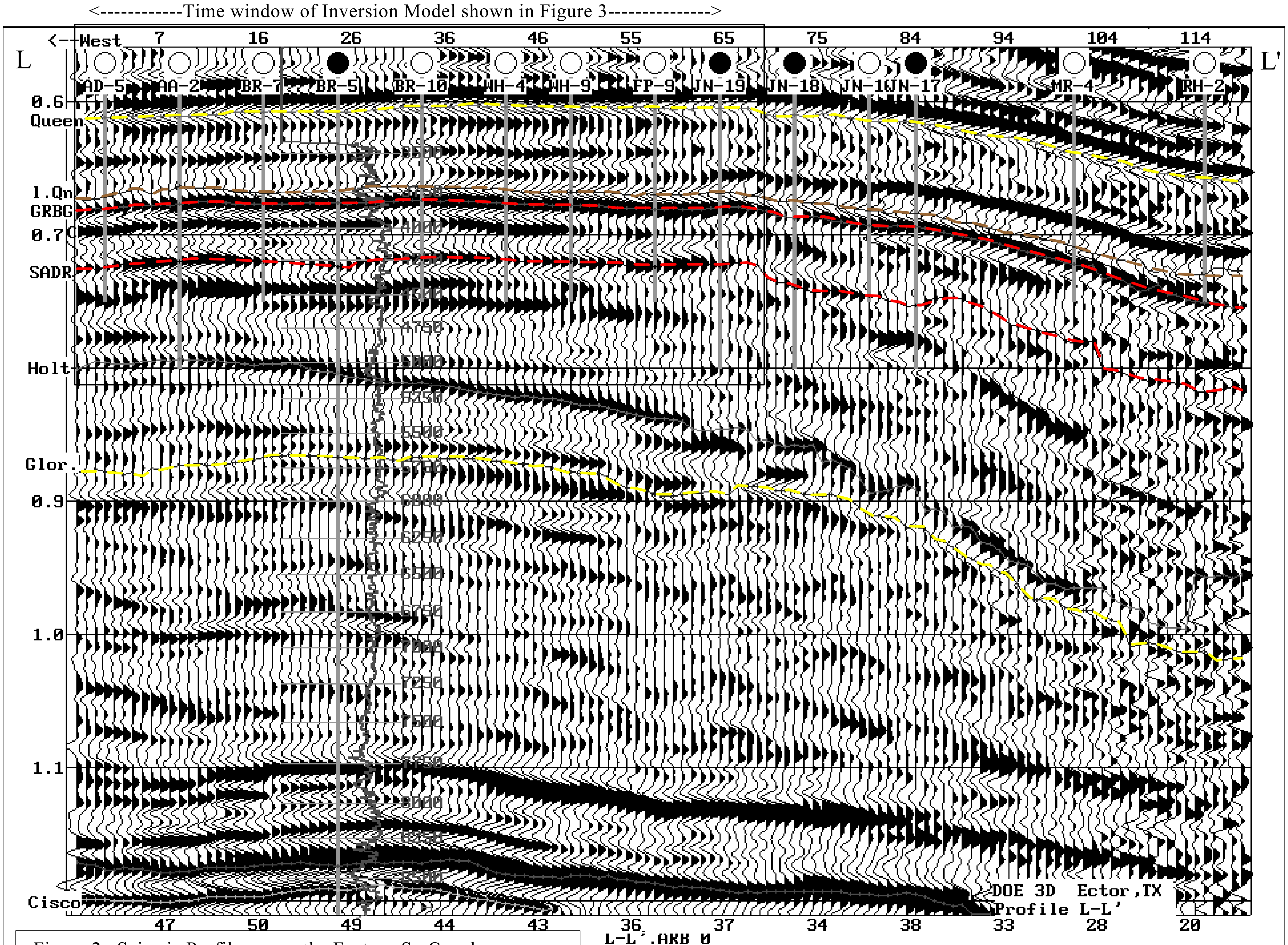


Figure 2. Seismic Profile across the Foster - So.Cowden 3D seismic survey, showing some structural and stratigraphic features of the project.

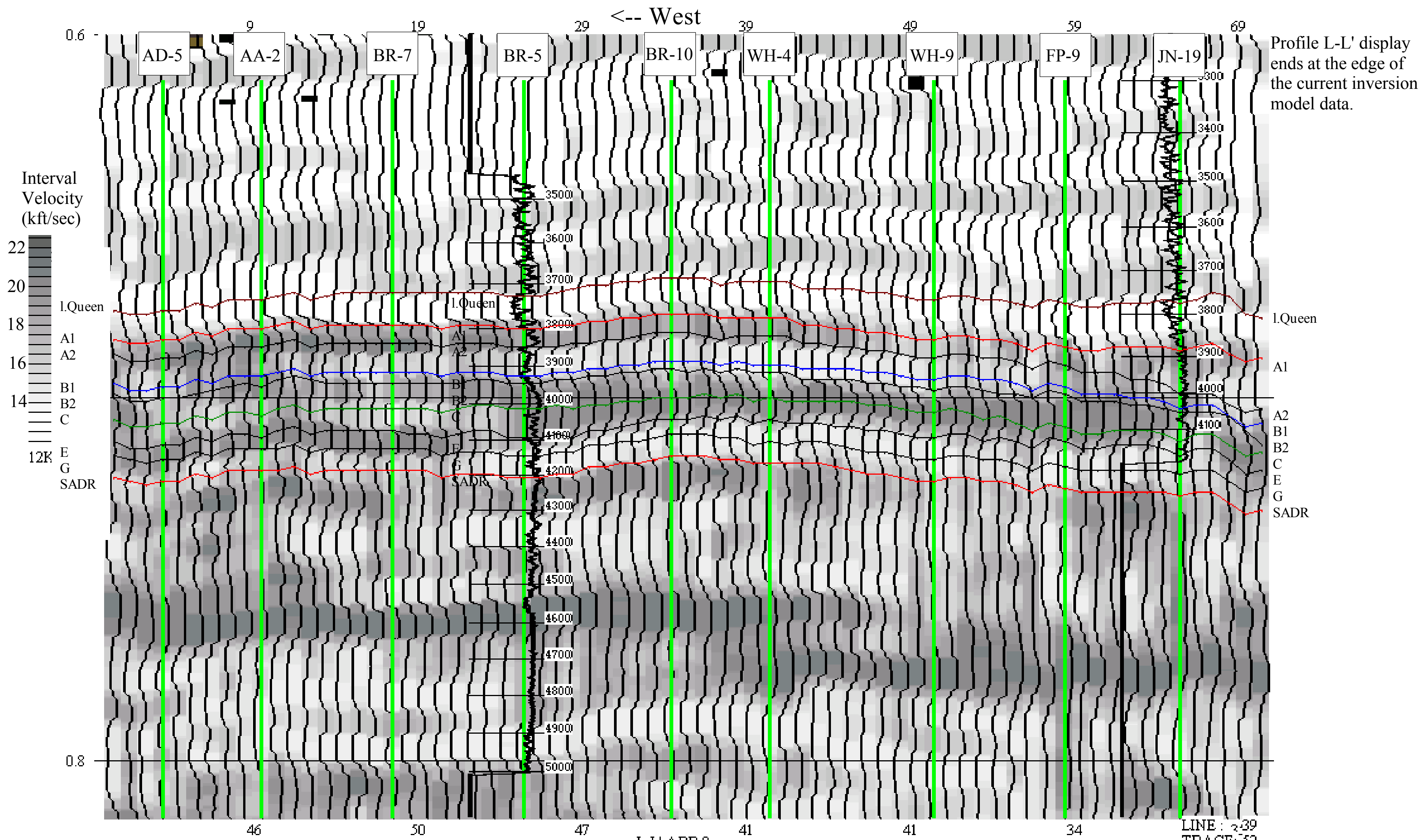


Figure 3. Profile L-L' (partial) from the inversion model data volume showing ties with wells and sonic logs.

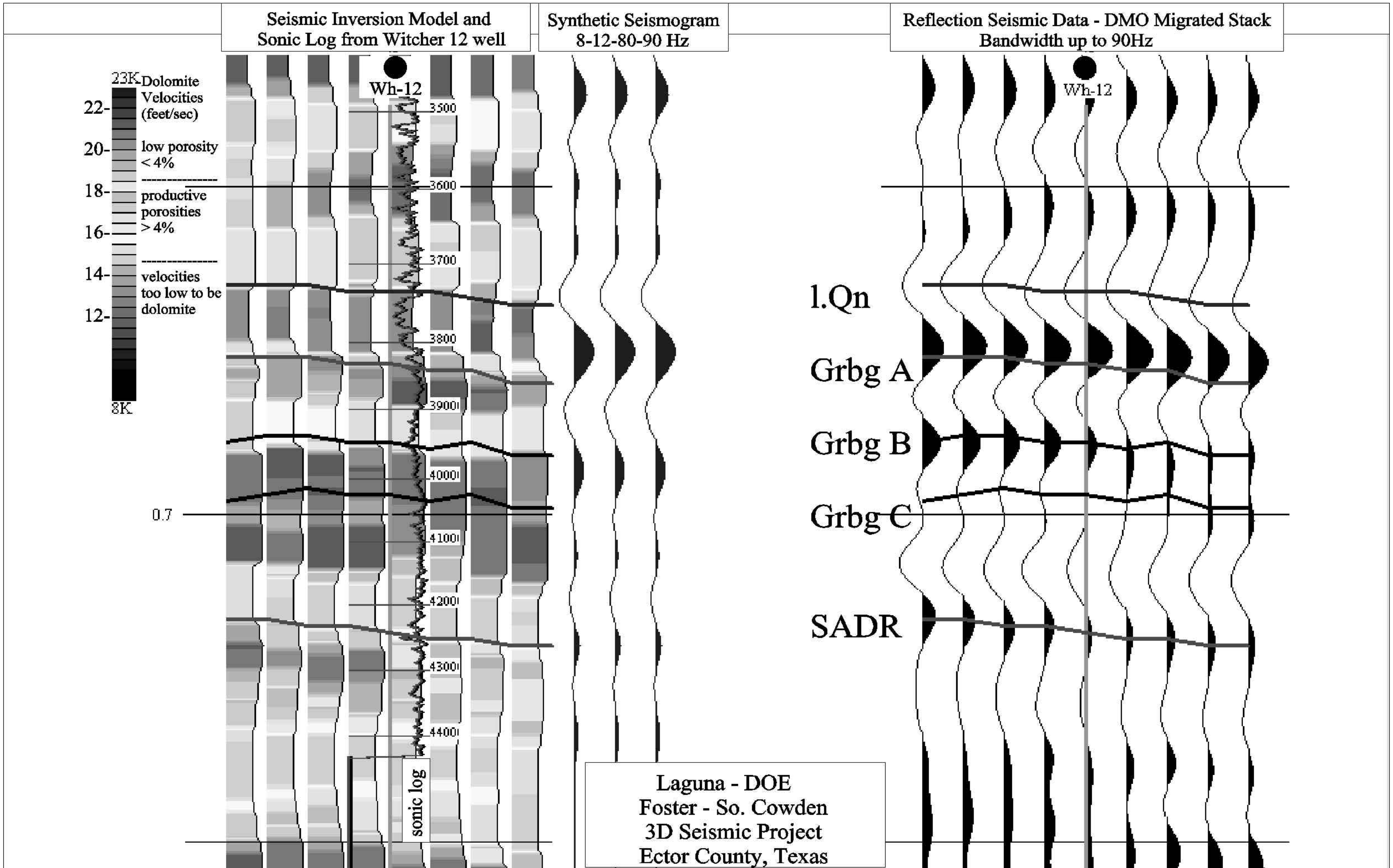


Figure 4. A comparison of Seismic Inversion Model traces to the Reflection Seismic data input traces. Inverted traces compare to the sonic log curve in velocity values and shape. Resolution of about 50 feet is achieved from the Inversion Model traces, compared to the one foot resolution of the sonic log. The synthetic seismogram trace, a product of the sonic log, compares well to the reflection seismic traces for major reflectors. Amplitudes are strong in the lower Grayburg and San Andres; the Inversion Model shows more velocity contrast there than the sonic log.

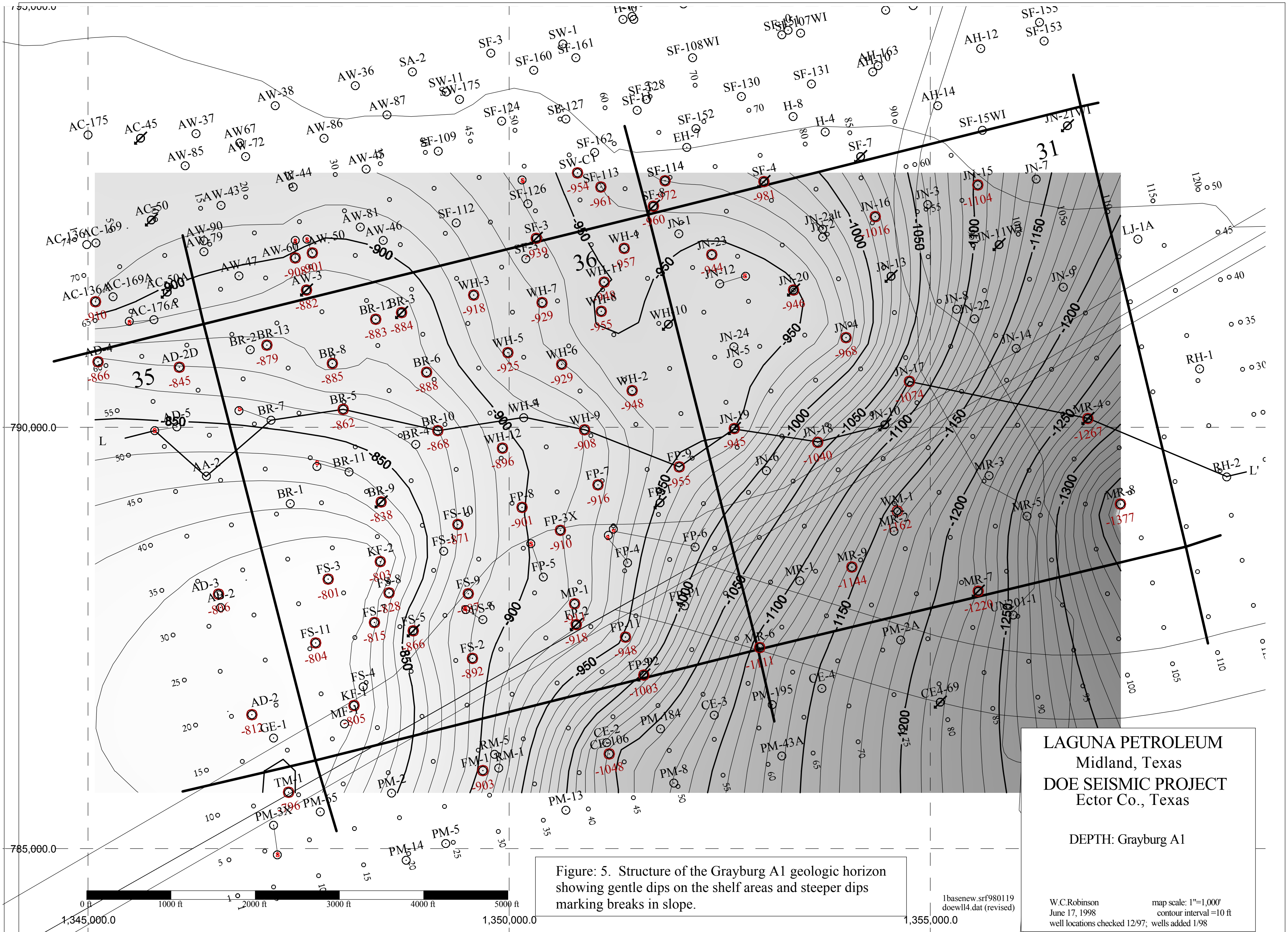


Figure: 5. Structure of the Grayburg A1 geologic horizon showing gentle dips on the shelf areas and steeper dips marking breaks in slope.

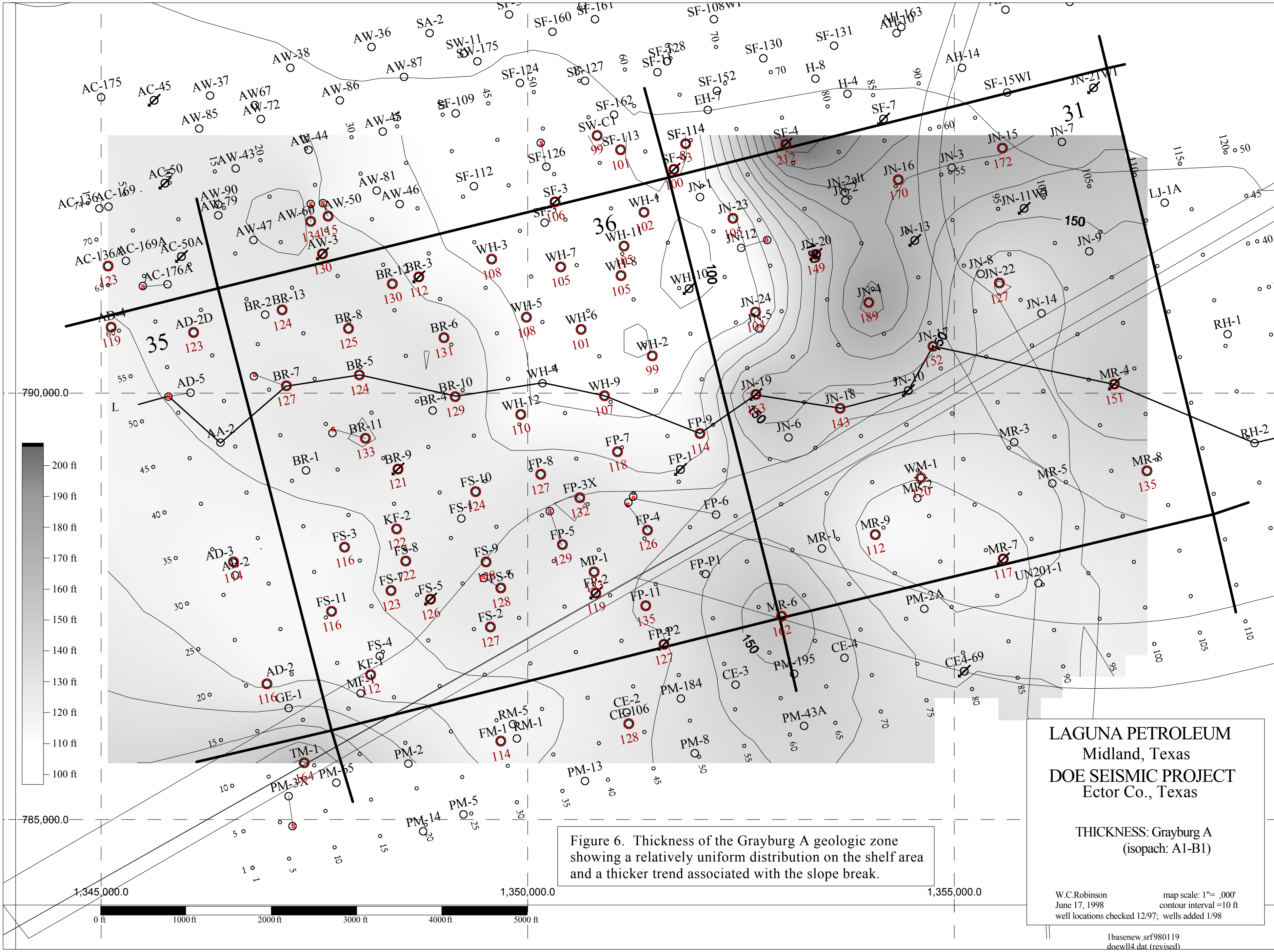


Figure 6. Thickness of the Grayburg A geologic zone showing a relatively uniform distribution on the shelf area and a thicker trend associated with the slope break.

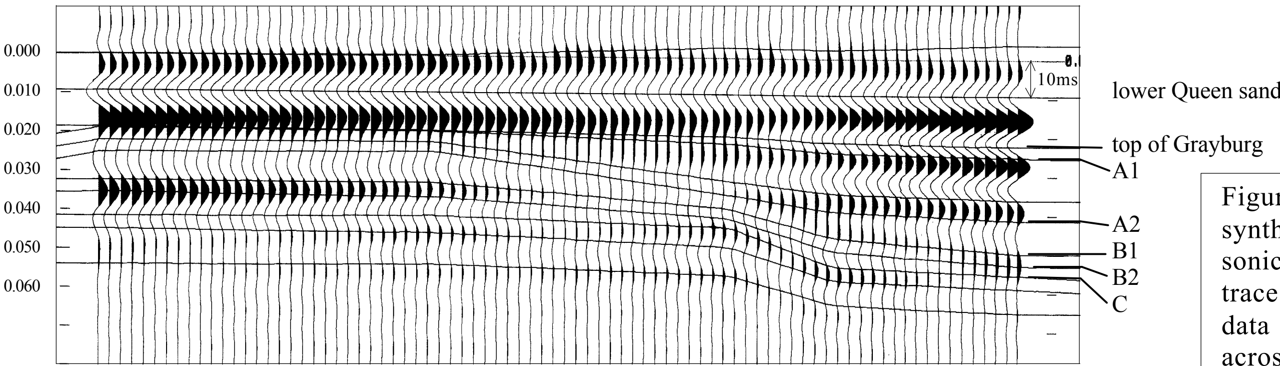


Figure 7 . A seismic forward model made of synthetic seismograms generated from well sonic logs and interpolated logs. These traces represent the expected changes of seismic data character due to geologic variations across the survey discussed in this report.

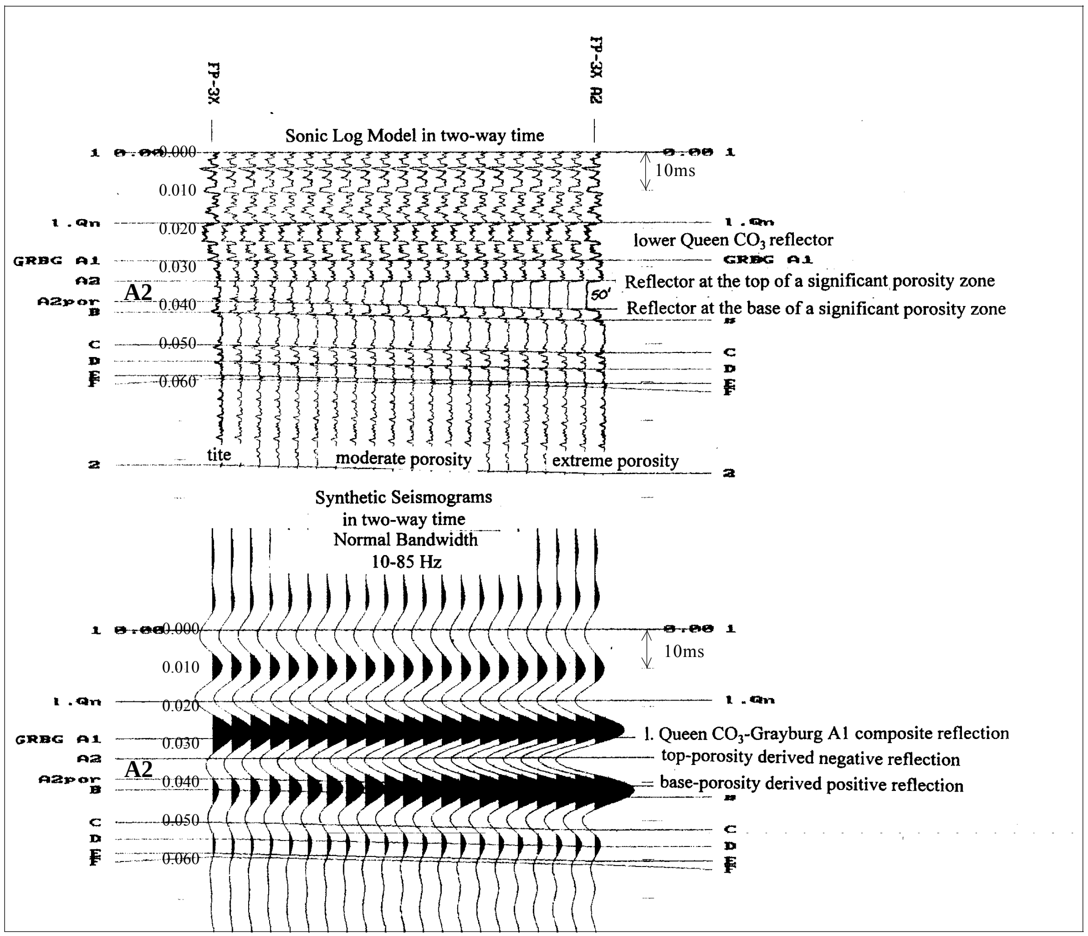


Figure 8 . A seismic forward model similar to Fig. 7, but changes are made to only a single sonic log. The amount of porosity in the A2 zone is varied from very low (left) to very high (right). The purpose is to create a significant pair of impedance contrasts, at the top and the base of the modeled porous unit. The seismic response is a trough, then peak reflection having increased strength with increased porosity.

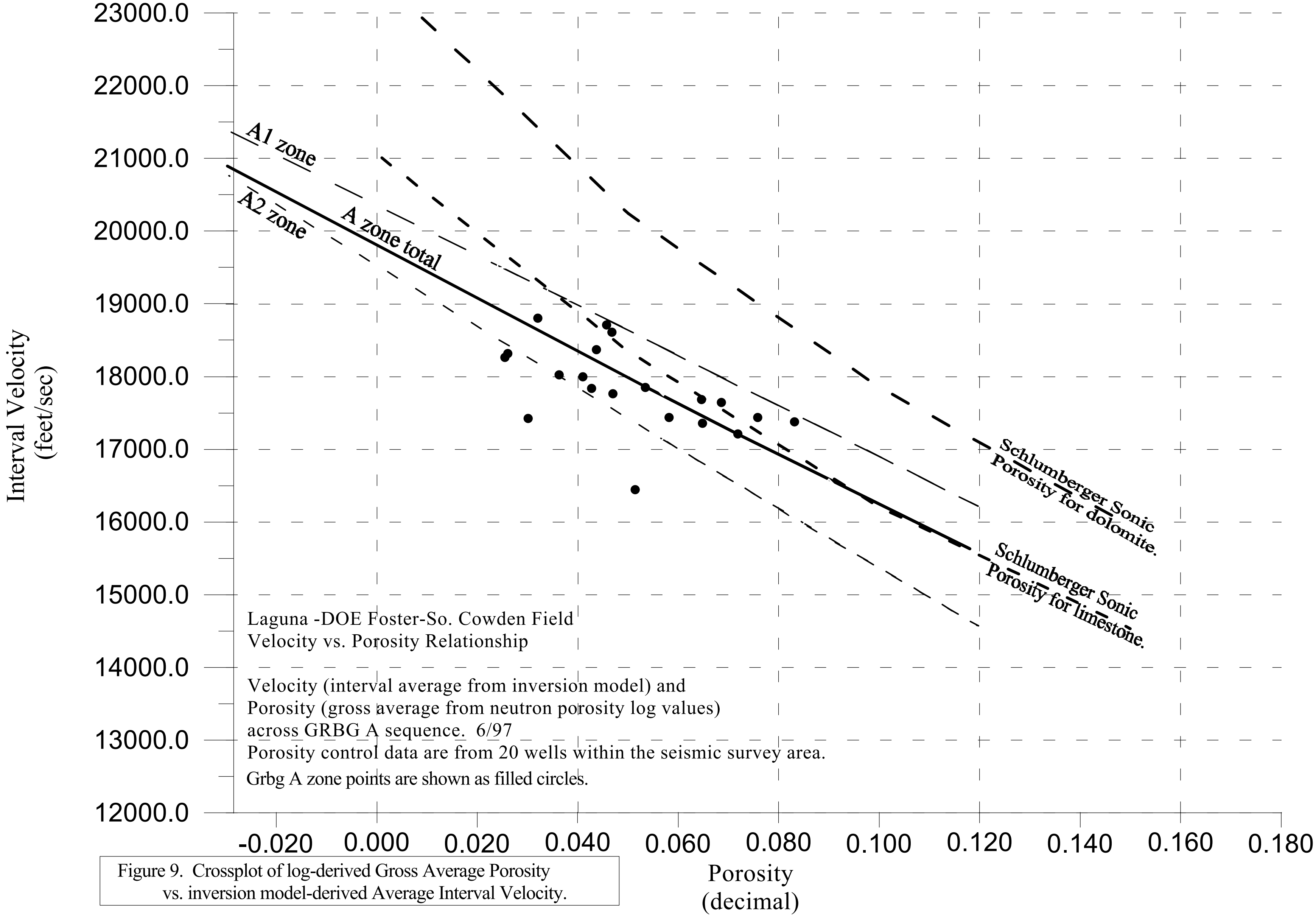


Figure 9. Crossplot of log-derived Gross Average Porosity
vs. inversion model-derived Average Interval Velocity.

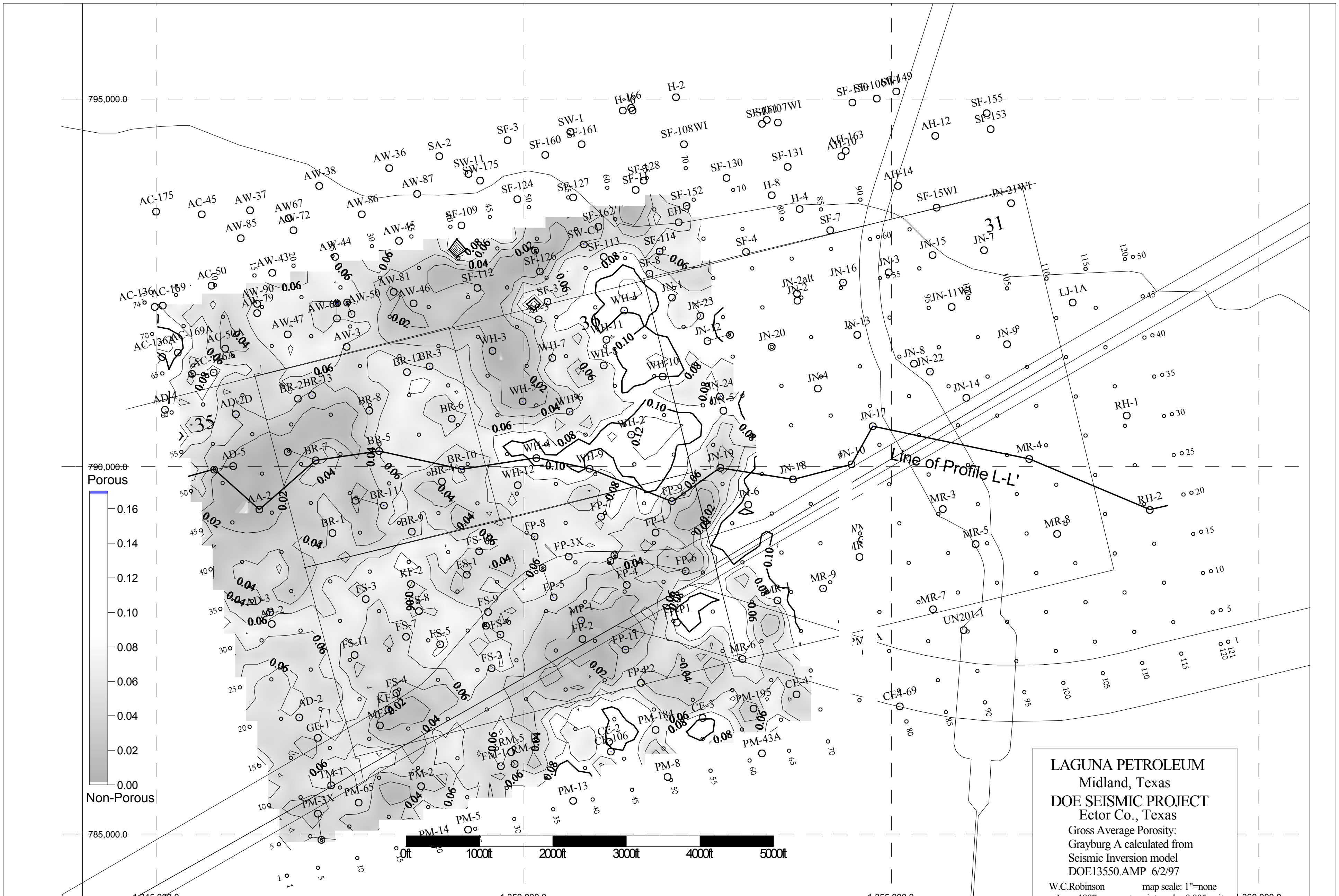


Figure 10. Seismic Inversion-Derived Gross Average Porosity Grayburg A zone.

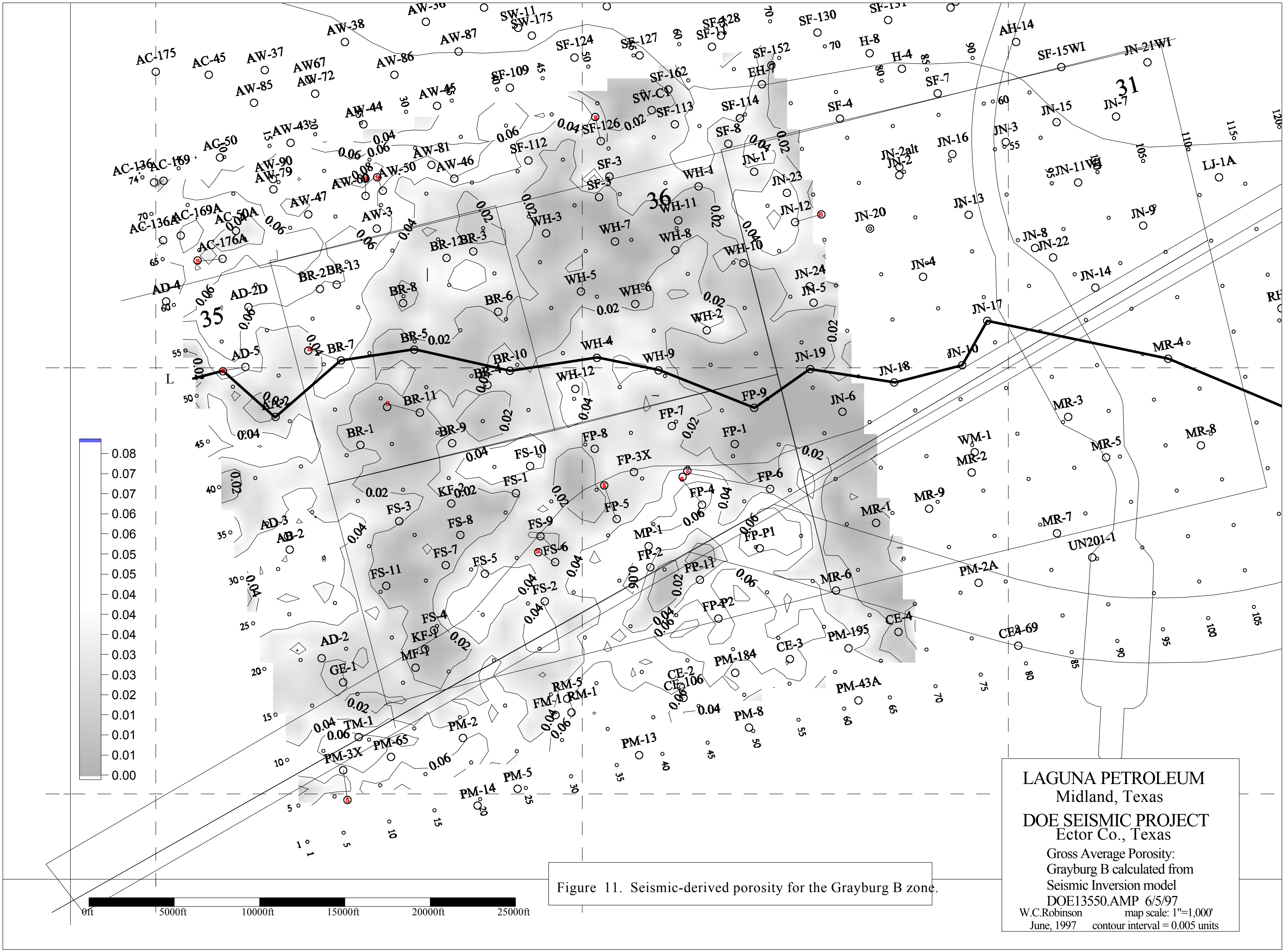


Figure 11. Seismic-derived porosity for the Grayburg B zone.

Well Name	Production Prior to Frac			Initial Production After Frac			Stabilized Production After Frac		
	BOPD	MCFD	BWPD	BOPD	MCFD	BWPD	BOPD	MCFPD	BWPD
Brock #13	0	0	0	80	20	313	30	3	125
Brock #5	6	1	6	72	10	200	43	10	110
Brock #6	3	1	9	38	10	220	22	4	110
Foster Pegues #8	2	0	13	25	2	455	22	2	455
H. C. Foster #8	5	1	45	17	2	150	17	2	150
Witcher #1	11	60	2						
Total									

Figure 12. Results of Refracture Stimulation Program

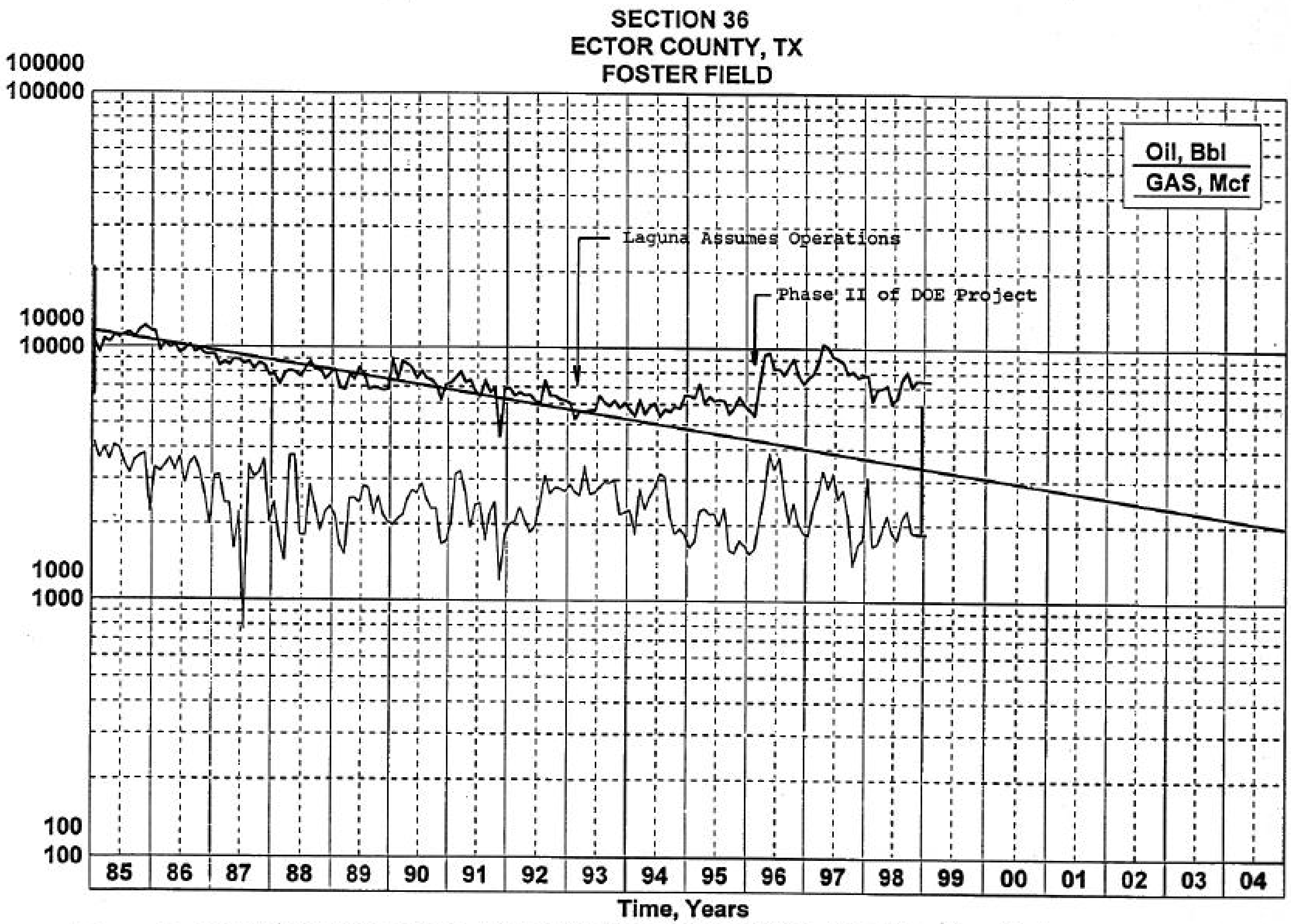


Figure 13. Foster Field Production. Note production increase since inception of project.